U.S. Department of Energy
Study of Economic Dispatch under Section 1234 of the Energy Policy Act of 2005
Response of Cowlitz, Grant and Pend Oreille County PUDs
September 21, 2005

General Response

Cowlitz, Grant and Pend Oreille County Public Utility Districts are publicly-owned utilities that own and operate generation resources in the State of Washington. The three PUDs recognize that this is the first implementation of DOE's new responsibilities under the Energy Policy Act of 2005, and that the Department is working within tight schedules stipulated by Congress. However, the questionnaire that is the subject of this response suffers from the lack of some basic definitions and a lack of clarity in many areas. For example, economic dispatch can (and should) be defined for different time periods. Also, the questionnaire is apparently biased in its emphasis on non-utility generation. In future, the PUDs recommend that the Department circulate a draft questionnaire (or other study instruments) well in advance of any deadline for responses, so that industry participants can comment on the usefulness of the instrument. The following consists of answers to DOE's specific questions from the perspective of the three PUDs.

1) What are the procedures now used in your region for economic dispatch?

   Economic dispatch is performed by each control area operator, and many individual utilities that do not operate control areas, using the generation resources and market purchases/sales available to them. Several utilities that do not operate control areas nonetheless conduct economic dispatch within a constrained set of resources and market opportunities. Economic dispatch overall is ensured by the fact that each decision maker takes into account the incremental or marginal costs of its own resources and the prices of purchases/sales that are available from the spot market. These decision makers include the Bonneville Power Administration, individual investor-owned utilities, and individual publicly-owned utilities such as the three PUDs.

   Marketers and IPPs also practice economic dispatch by choosing between (a) operating their own plants or taking delivery from their own contracts, versus (b) making spot purchases in the market to meet obligations to deliver. These arrangements will differ according to the contracts entered into by marketers and IPPs.

   Utilities and control area operators balance their total portfolios on a day-ahead (preschedule) basis at lowest possible cost, taking into account expected loads, expected flows of water into hydroelectric resources, and day-ahead market prices for purchasing and selling power. Portfolios are rebalanced in real-time to adjust for changes from forecasts used at preschedule: loads, resources, and market prices. Economic dispatch includes offers to deliver to and purchase energy from non-utility generators, such as the Centralia coal plant in western Washington, which is owned *by TransAlta. Settlements for purchases and sales in the market are normally at the Mid-Columbia Index, which is published by Dow Jones Indexes, part of Dow Jones and Company. Day-ahead transactions in the market are conducted by telephone and by using brokerage services such as Intercontinental Exchange (ICE; see www.intcx.com).*

In real time, utility dispatchers normally displace thermal units with hydro generation to the greatest extent possible depending on the availability of water and non-power constraints that limit the ability of hydro units to move up or down. Again, this displacement is based on a rebalancing of the utilities' portfolios with the objective of minimizing cost, subject to reliability constraints and technological limits on resource operation (e.g., non-power constraints on hydroelectric generators). Real-time redispatch normally takes place by telephone contact among dispatchers, who develop long-term relationships with other market participants that permit quick transmittal of information about which entities are buying and which are selling on any given hour.

Utilities that are largely dependent on hydropower are constantly rebalancing their portfolios to make best economic use of their "discretionary water": hydro energy that can be either stored for later use or sold into the market now. Discretionary water may be sold forward for up to several months, depending on market conditions and the conditions of individual reservoirs.

All control areas in the Northwest are signatories to the Northwest Power Pool Reserve Sharing Agreement, which provides the ability of control area operators to call on each other to provide contingency reserves (spinning and non-spinning) in the event of an outage (generation or transmission) within their control area that triggers the need for reserves. Control areas with multiple generation resources will respond with their least expensive resource(s), again subject to reliability criteria and non-power operating constraints on generation units. Depending on the counterparty, the energy delivered when these reserves are called upon is either returned or settled financially, again at a market price such as the Mid-C Index.

Economic dispatch of hydroelectric generation must also take into account the forward opportunity cost of production: what potential future revenues are being foregone if scarce (energy-constrained) fuel is used today to generate power? Owners and operators of hydroelectric generation maximize the value of their scarce fuel in response to market price signals, for example by purchasing power during off-peak periods, holding water in reserve, and generating with hydropower during peak periods. This contributes to the overall value of economic dispatch because a scarce fuel is being used in its highest value period. This is sometimes referred to as "dispatch to market" rather than "dispatch to load". In all cases load obligations are met, but at the lowest possible cost to consumers.

Economic dispatch also involves end-use generation, e.g., cogenerators owned by retail industrial customers. Some end-use generation in the region is designated as

Network Resources under Network Transmission service agreements, and this end-use generation is dispatched along with other resources and power supplies (utility-owned, non-utility, and market).

Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

Dispatch is performed by each control area and many utilities separately, but takes into account market opportunities that are broader in scope than the utility's control area. Utilities in the Northwest routinely trade with counterparts in California, other parts of the Western Electricity Coordinating Council (WECC), and even in the Eastern Interconnection.

2) Is the Act's definition of economic dispatch (see above) appropriate?

Section 1234 of the Energy Policy Act defines economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities." This definition is appropriate and represents the actual behavior of utilities in the Northwest.

Over what geographic scale or area should economic dispatch be practiced?

There is no simple or single answer to this question. The geographical scale of economic dispatch must take into account the availability of transmission capacity for the displacement of more expensive resources. Economic dispatch must also take into account security and reliability considerations, which limit the ability of distant resources to be included in economic dispatch decisions. For example, it is not possible to rely on unit commitments in Arizona to meet reserve requirements in the Northwest, because in real time there is no guarantee of transmission capacity to deliver the energy called on under the contingency reserves.

Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

Economic dispatch in a hydro-based system such as the Northwest must take into account non-power constraints, including flood control, fish passage, navigation and recreation. All hydroelectric generating projects in the region are subject to some form of non-power constraint at some time. System operators take these constraints into account in every time frame (day-ahead and real-time) and dispatch resources to minimize cost within such constraints.

Economic dispatch also takes into account the nature of the product being offered. Many market-based transactions take place under the Western Systems Power Pool (WSPP) Agreement, which defines three types of products: Schedules A, B, and C.

Schedule A is Economy Energy service, which can be interrupted at any time with notice. Schedule B is Unit Commitment Service, which is dependent on the performance of a specific generating unit. Schedule C is for firm sales or exchanges. Very little is traded in the WECC under Schedule A. Non-utility generators who are interested in selling under Schedule C may purchase operating reserves from a third party to back up their units and make sales that are "firm on the hour". The Bonneville Power Administration has a specific rate schedule for Control Area Services – Operating Reserves (ACS-06), under which non-utility generators (and others with reserve obligations) in the BPA control area may purchase operating reserves to "firm up" their supply offers that are unit-dependent. This increases the liquidity in the market, by permitting non-utility generators to make firm offers to deliver energy.[1]

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation?

All generation must meet specified reliability criteria, including operating reserves. Economic dispatch procedures for different types of generation do not distinguish between "utility-owned" and "non-utility", but between generation that is offered in the market under different WSPP schedules or other arrangements. A non-utility generator that has purchased operating reserves is able to offer WSPP Schedule C service on the same basis as utility-owned generation that is also supported by operating reserves (either owned or purchased).

Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above?

To our knowledge, there are no federal or state rules or tariff procedures that require any particular form of dispatch. The actual form of dispatch follows the definition of economic dispatch in the statute.

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch?

Improvements could be made in the liquidity of markets for control area services, which might help non-utility generators offer more firm energy under WSPP Schedule C. The Northwest Reserve Sharing Agreement could be expanded to include a role for Independent Power Producers, working with their host control areas.

[1] *Another standard agreement that is used in the Northwest is the Edison Electric Institute's Standardized Master Power Contract. In addition to the standardized agreements, there are many bilateral contracts.*

If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts?

First, it is not clear that "economic dispatch" has any specific impact on non-utility generation, so the premise of this question is arguable. Second, all else equal, greater use of non-utility generation, compared with today, should have no impact in any of these areas, compared with utility-owned generation. Both types of generation must meet reliability criteria (although the criteria will depend on whether the non-utility generation is itself a control area), both types of generation may be hydro, thermal or renewable, and both types of generation may have environmental impacts. The main issue is not ownership of the generation. Ownership by itself should have no impact in any of these areas.[2]

How would this affect retail customers in particular states or nationwide?

This requires speculation. Again, ownership should not be an issue, if the generation meets reliability requirements and is able to offer an economic price.

5) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch?

This question is unclear. Economic dispatch is used today by all entities that are responsible for meeting load. It is not clear what "greater use" might mean.

[2] *This is an example of an area where the questionnaire could be improved: what is meant by "mix of energy and capacity"? Different amounts of energy and capacity? Different types of resources?*